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US 5251479 A US 4520666 A

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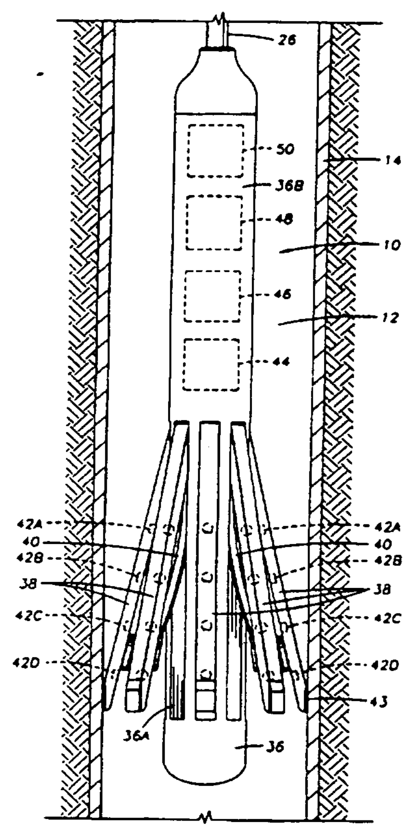
ONLINE:WPI

(54) Apparatus and methods for determining fluid regimes in a wellbore

(57) An apparatus for imaging thermal properties of fluids in a wellbore includes a tool mandrel 36 adapted to traverse the wellbore, a plurality of temperature sensors 42 disposed at spaced apart locations along radially extendible arms 38 attached to the mandrel, means for measuring the temperature sensed at each one of the sensors, and means to ascertain the arm positions and thus the location of each of the sensors in the wellbore cross-section. In a preferred embodiment, the tool includes a means for applying a current pulse to the temperature sensors momentarily to raise their temperatures, so that the thermal transient response of the fluid in contact with each sensor can be determined. There is also described a method of determining the flow regime in a wellbore penetrating an earth formation, the method including the steps of measuring the temperature of fluids in the wellbore at spaced apart locations within the cross-sectional area of the wellbore using a tool having a plurality of temperature sensors 42, and determining the flow regime by generating a temperature map of the wellbore and comparing the map with maps of known flow regimes; heating current pulses may again be used, thus generating a map of the thermal response of the fluid.

FIG. 2



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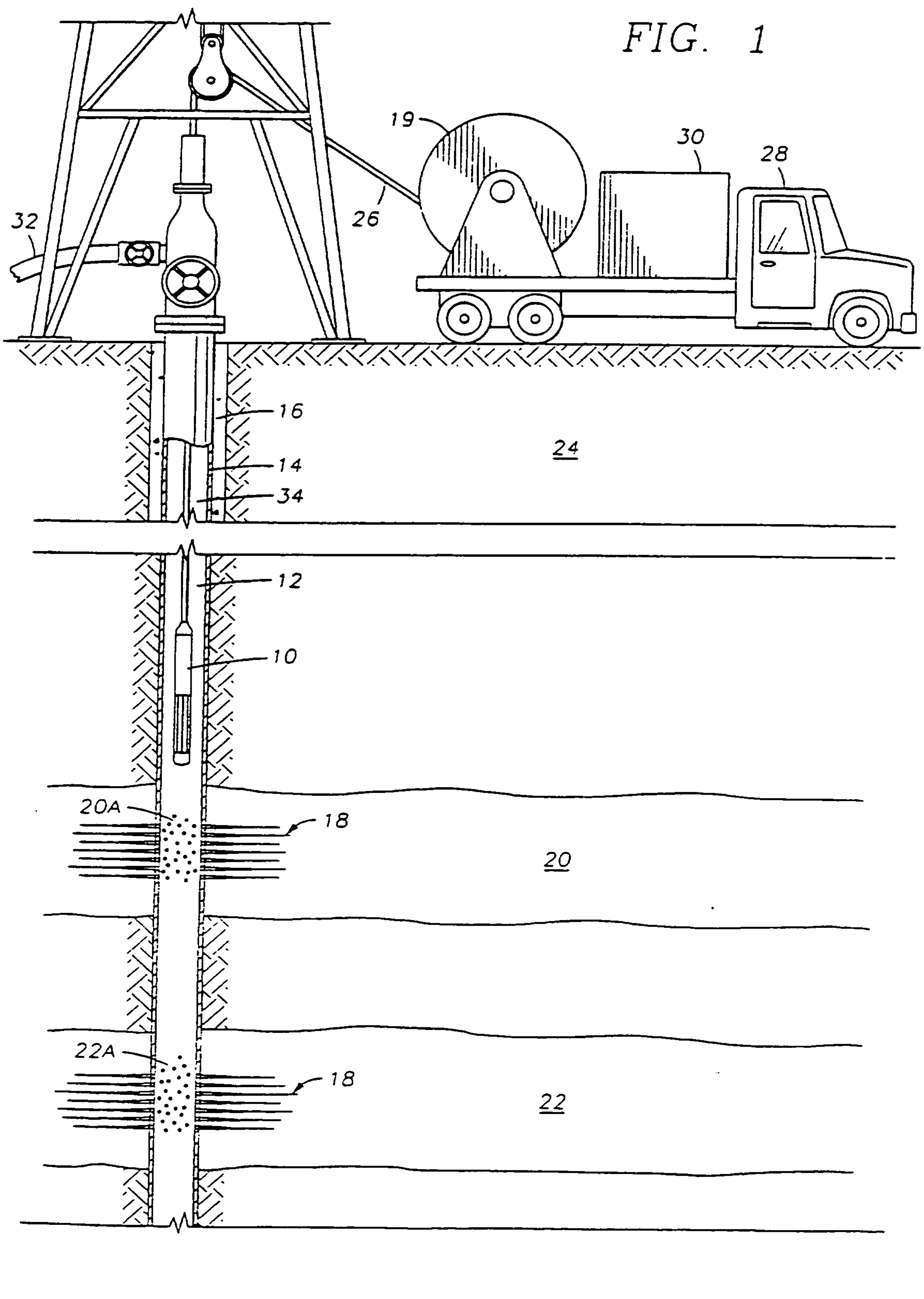


FIG. 1
19
30
28
32
26
16
24
14
34
12
10
20A
18
20
22A
18
22

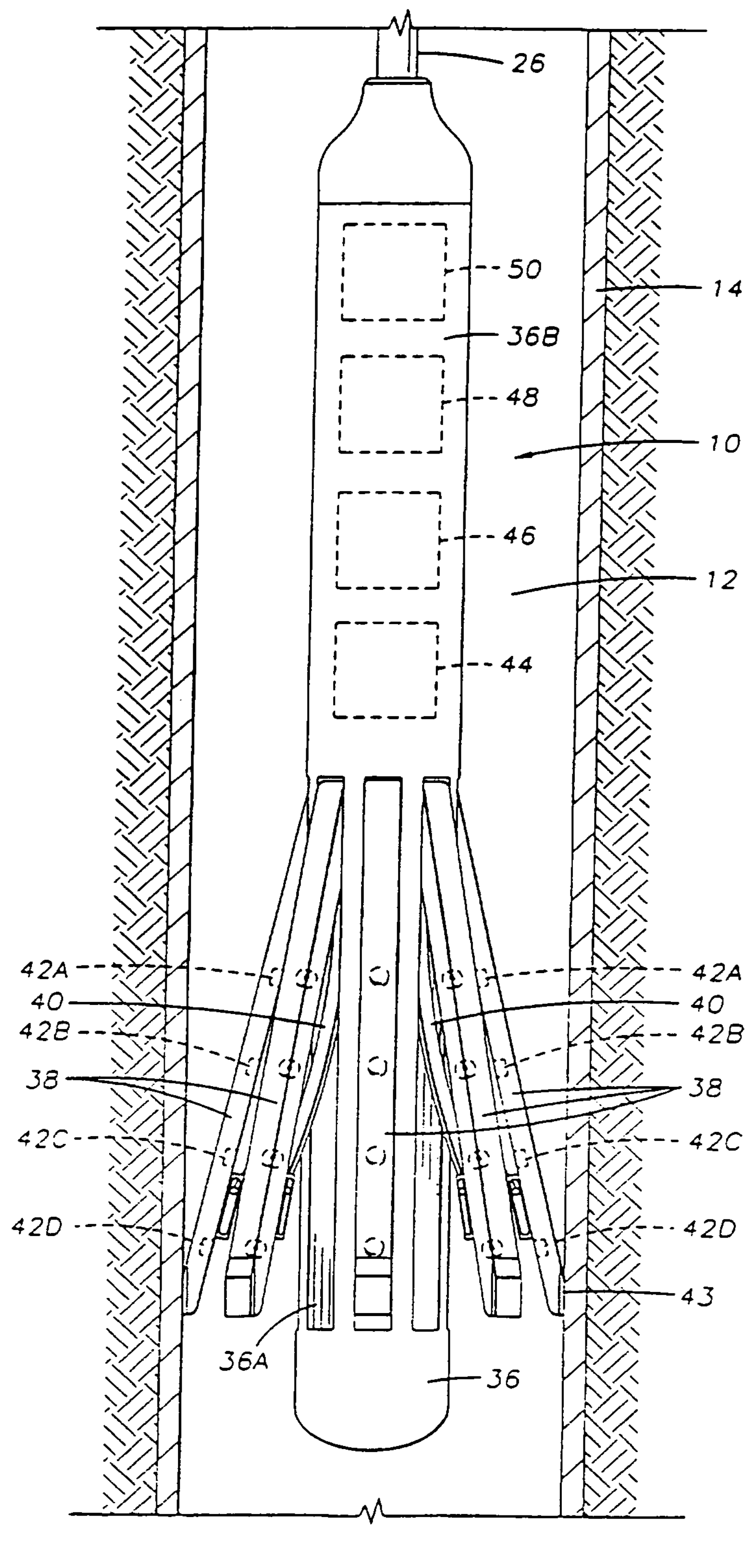
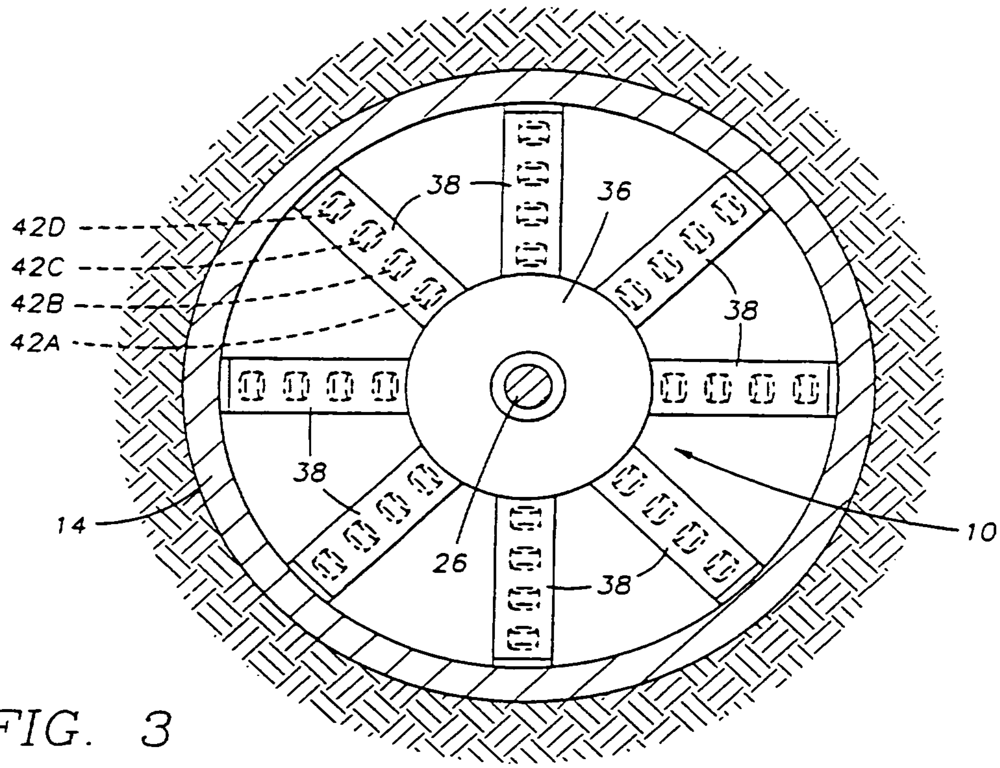
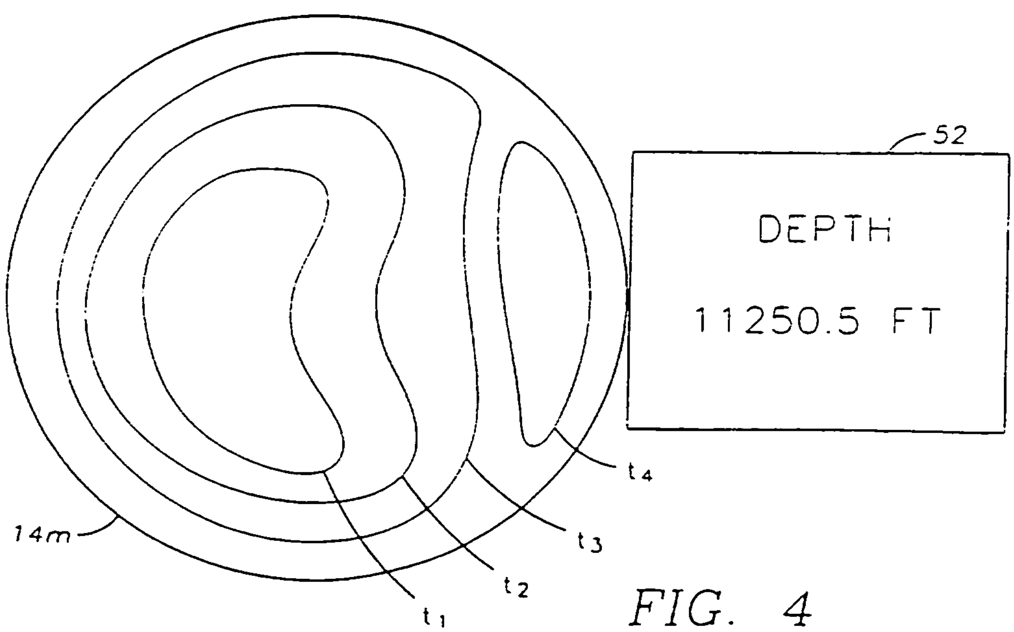

26
50
14
36B
48
10
46
12
44
42A
42A
40
40
42B
42B
38
38
42C
42C
42D
42D
43
36A
36

FIG. 2



42D
42C
42B
42A
38
36
38
38
38
14
26
38
10

FIG. 3



52
DEPTH
11250.5 FT
t4
t3
t2
t1
14m

FIG. 4

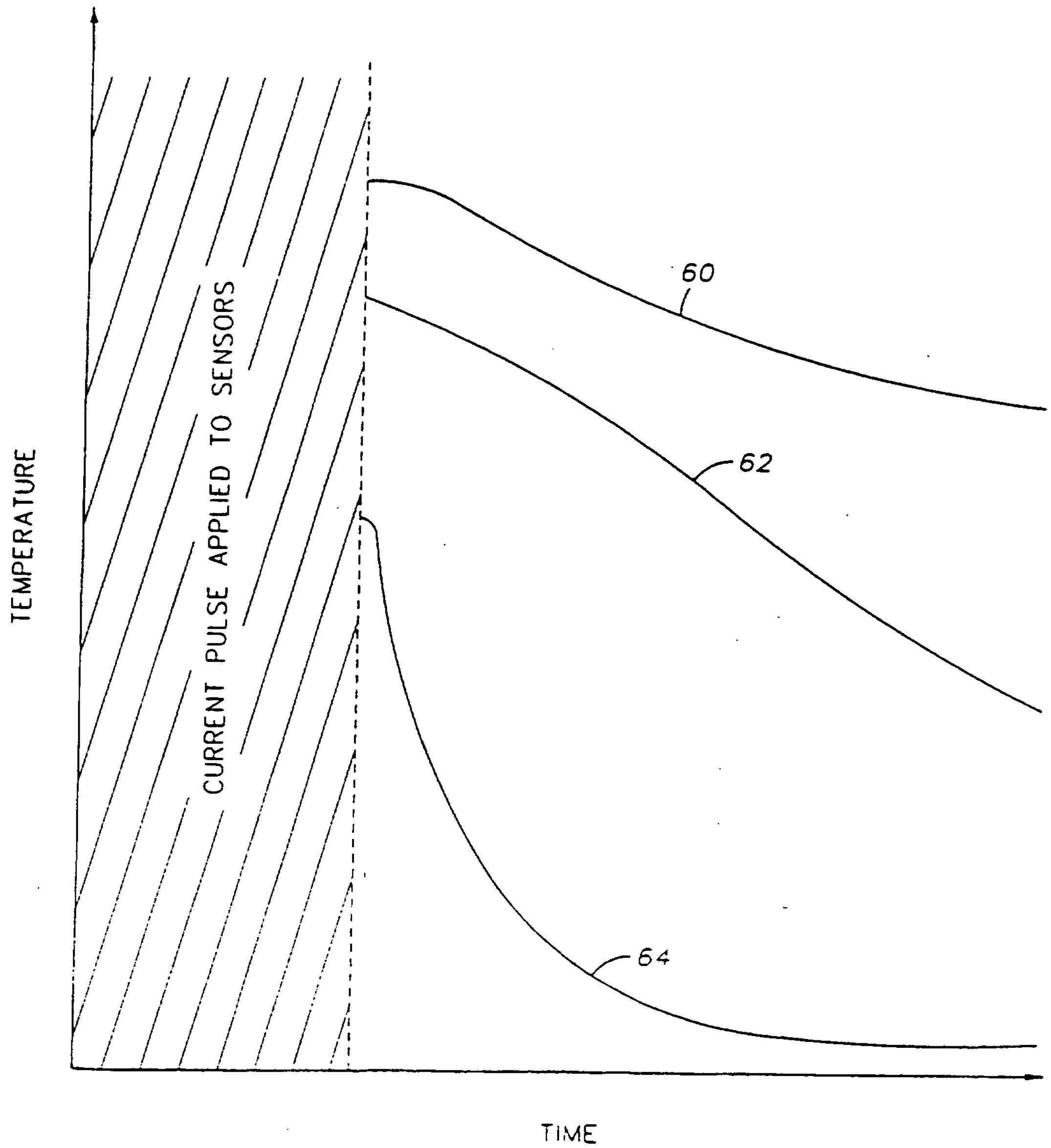


FIG. 5

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APPARATUS AND METHODS FOR DETERMINING FLUID REGIMES IN A WELLBORE

The present invention relates to the field of logging tools or sondes used for evaluating wellbores drilled through earth formations and is concerned, more specifically, with determining fluid regimes in a wellbore, such as the quantities and types of fluids flowing through a wellbore.

Wellbores drilled into petroleum reservoirs within earth formations for the purpose of extracting oil and gas typically produce the oil and gas from one or more discrete hydraulic zones traversed by the wellbore. When a wellbore is completed the zones are hydraulically connected to the wellbore. The oil and gas can then enter the wellbore, whereupon they can be transported to the earth's surface entirely by energy stored in the reservoir, or in combination with various methods of pumping.

Hydraulic zones penetrated by some wellbores can traverse a substantial length. In other wellbores a plurality of zones can be simultaneously hydraulically connected to the wellbore. In such cases, for the wellbore operator to maximize the efficiency with which the oil and gas are extracted from the reservoir it is useful to determine the rates at which oil, gas and other fluids such as water enter the wellbore from any particular point along the length of any particular hydraulic zone.

Various instruments are known in the art which can be used to determine the rates at which the fluids enter the wellbore from any particular point within any hydraulic zone. The instruments known in the art for determining the rates of fluid entry into the wellbore are called production logging tools.

Production logging tools are typically lowered into the wellbore at one end of an armored electrical cable. The tools can include sensors which are responsive to, among other things, the fractional volume of water filling the wellbore, the density of the fluid within the wellbore, and the flow velocity of the fluid in the wellbore. A record is typically made, with respect to depth within the wellbore, of the measurements made by the various sensors so that calculations can be made of the volumes of fluids entering the wellbore from any depth within the wellbore.

Methods known in the art for calculating the relative volumes of fluids entering the wellbore from production logging tool measurements generally require the use of laboratory determined models of the responses of the various production logging sensors to a range of volumetric flow rates of the different fluid phases in the wellbore. All of the sensor response models known in the art are based on an assumed "flow regime" of the fluids entering the wellbore. The flow regime is a descriptive name for the manner in which any or all of the individual phases of fluids in the wellbore travel along the wellbore, the phases typically being liquid oil, gas and water. A discussion of flow regimes can be found, for example in "A Comprehensive Mechanistic Model for Upward Two-Phase Flow in Wellbores", Ansari et al, Society of Petroleum Engineers, paper no. 20630.

The methods known in the art for calculating the relative volumes of fluids entering the wellbore is that the methods known in the art do not account for the fact that the actual flow regime in the wellbore may be different from the particular flow regime assumed in the sensor response model. The calculations of relative volumes based on an assumed flow regime can therefore be erroneous.

One can determine the flow regime by the use of iterative calculation techniques to fit the actual production logging tool measurements to a particular flow regime and then calculate the fluid volumes after determining the flow regime. Iterative calculation techniques can be difficult and time consuming to perform and ultimately do not determine the flow regime to a high degree of certainty.

According to one aspect of the present invention there is provided an apparatus or method for mapping the distribution of thermal properties of the fluids within the wellbore, so that the distribution of different types of fluids and consequently the flow regime in a wellbore can be determined to a high degree of certainty.

According to a second aspect of the invention there is provided an apparatus for determining the distribution of thermal properties of fluids within a wellbore including a tool mandrel adapted to traverse the wellbore, a plurality of temperature sensors disposed at spaced apart locations along extensible arms attached to the mandrel and means for measuring the temperature sensed at each one of the sensors.

In a preferred embodiment of that aspect, the tool includes a means for applying a current pulse to each of the temperature sensors momentarily to raise their temperatures, so that the thermal transient response of the fluid in contact with each sensor can be determined.

According to a third aspect of the invention, there is provided a method of determining the flow regime in a wellbore penetrating an earth formation, the method including the steps of measuring the temperature of fluids in the wellbore at radially spaced apart locations within the wellbore using a tool having a plurality of temperature sensors and determining the flow regime by generating a temperature map of the wellbore and comparing the map with maps of known flow regimes. One embodiment of that method includes the steps of applying current pulses to the temperature sensors on the tool and determining the thermal transient response of the fluids in contact with each sensor. A map can them be generated of the thermal transient response and the transient map is compared to maps of transient response in known flow regimes.

Other aspects of the invention are exemplified by the attached claims.

For a better understanding of the invention, and to show how the same may be carried into effect, reference will now be made, by way of example only, to the accompanying drawings, in which:-

Figure 1 shows a well logging tool disposed in a wellbore;

Figure 2 shows the tool of Figure 1 in detail;

Figure 3 shows the tool of Figure 1 in an end view;

Figure 4 shows an isothermal contour plot compiled from temperature measurements made by the tool of Figure 1; and

Figure 5 shows a graph of thermal transient response for various fluids in the wellbore of Figure 1.

Figure 1 shows a well logging tool 10 being lowered into a wellbore 12 drilled through an earth formation 24. The tool 10 is connected to one end of an armored electrical cable 26. The cable 26 can be extended into the wellbore 12 by means of a winch (not shown separately) forming part of a logging unit 28 as is understood by those skilled in the art. The other end of the cable 26 is electrically connected to surface electronics 30 also forming part of the logging unit 28. The surface electronics 30 can include a computer (not shown separately) for performing calculations on measurements made by the tool 10, as will be further explained. The tool 10 imparts signals to the cable 26 corresponding to measurements made by temperature sensors in the tool 10, as will be further explained. The signals imparted to the cable 26 are received and interpreted by the surface electronics 30, wherein the various temperature related measurements made by the tool 10 can be derived, as will also be further explained.

The wellbore 12 is shown penetrating a first zone 20 and a second zone 22, both of which can form part of the earth formation 24. The wellbore 12 is further shown as "completed" by having a steel casing 14 coaxially inserted therein. The casing 14 is hydraulically sealed by cement 16 filling an annular space between the casing 14 and the wellbore 12, as is understood by those skilled in the art. The first zone 20 and the second zone 22 are typically hydraulically connected to the wellbore 12 by perforations 18 made through the casing 14 and through the cement 16, as is also understood by those skilled in the art.

The first zone 20 may be spaced apart from the second zone 22 by a substantial vertical distance, and therefore can have a substantially different fluid pressure within its pore space from that of the second zone 22. The pressure differential is principally caused by the earth's gravity, as is understood by those skilled in the art. The first zone 20 may also be of a different rock composition and may contain different relative volumes of oil, gas and water within its pore spaces from those of the second zone 22. For these reasons and for other reasons known to those skilled in the art the fluid 20A from the first zone 20 may enter the wellbore 12 at different rates and the fluid 20A may have different fractional volumes of oil, gas and water from those of the fluid 22A entering from the second zone 22. The manner in which fluid flows in the wellbore 12, called the "flow regime", can be substantially different adjacent to the second zone 22 from what it is adjacent to the first zone 20, and the flow regime at either of these positions in the wellbore 12 may be substantially different from the flow regime of total produced fluid 34 which travels to the earth's surface.

The total produced fluid 34 is eventually conducted to equipment (not shown) at the earth's surface by a flowline 32 connected to the wellbore 12, wherein volumes of each of three phases of fluid, oil, gas and water, can be measured.

The tool 10 can be better understood by referring to Figure 2. An elongate, generally cylindrical, sonde mandrel 36 is be attached to the end of the cable 26. The mandrel 36 includes an interior chamber 36B which is sealed to exclude entry of the fluid in the wellbore 12. The chamber 36B forms an enclosure for several electronic sections.

The lower end region 36A of the mandrel 36 can consist of a highly thermally conductive material such as aluminum or brass and in this example is shaped matingly to receive a plurality of sensor arms 38 which can be pivotally attached to the mandrel 36 at a position where the lower end region 36A joins the main body of the mandrel 36. The pivotal attachment of the arms 38 enables them to fit substantially within the mating recesses of the lower end 36A when the arms 38 are fully retracted towards the mandrel 36 and enables extension of the arms 38 so that the end of each arm, such as the one shown generally at 43, can contact the wall of the casing 14. The end 43 of each arm 38 can be formed from an abrasion resistant material such as tungsten carbide to reduce wear. The arms 38 preferably are constructed from a material having very low thermal conductivity so that temperature differences within the cross-section of the wellbore 12 are not dissipated by the arms 38. A material suitable for the arms 38 can be graphite fiber reinforced plastics material.

The arms 38 can be urged into contact with the interior wall of the casing 14 by springs 40. Each arm 38 can include a means for indicating the amount of angular deflection (not shown separately for clarity of the drawing) from the closed position. Pivotal attachment means, means for urging and means for indicating the angular deflection (and consequently the amount of extension) of the arms 38 are known in the art and can include devices such as that disclosed, for example, in US Specification No. 4,121,345 issued to Roesner. The arms 38 can further include a mechanism (not shown separately) for selectively extending the arms 38 when the tool is inserted into the casing 14 to a depth of interest. Mechanisms for selectively extending and retracting the arms 38 are also known in the art and can include a mechanism such as one disclosed in the US Specification No. 4,121,345. The pivotal attachment means, means for selectively retracting and extending the arms and the means for indicating angular deflection as disclosed in the US Specification No. 4,121,345 are meant to serve only as examples of such means. As will be appreciated by those skilled in the art, many variations of such means can be devised which will perform the same functions for the arms of the tool disclosed herein.

The means for indicating the angular deflection (not shown) of the arms 38 can be electrically connected to that one of the electronic sections which is an angular deflection circuit 44 for generating signals indicative of the angular deflection of each one of the arms 38. In the present embodiment eight such arms 38 are pivotally attached to the mandrel 36 at an angular spacing of 45 degrees between each two of the arms 38. It is contemplated that other numbers of radially spaced apart arms 38 can equally be suitable so that the number of arms 38 and the angular separation therebetween should not be construed as a limitation.

Typically the tool 10 is lowered into the wellbore 12 with the arms 38 fully retracted to enable relatively unrestricted movement into the wellbore 12. Upon reaching a depth in the wellbore 12 below the zones 20 and 22 in Figure 1, the system operator can enter a command into the surface electronics (30 in Figure 1) to extend the arms 38 and the tool 10 can be slowly pulled out of the wellbore 12 while recording, with respect to depth, the measurements made by the tool 10.

Each arm 38 includes a plurality of temperature sensors, such as those shown generally at 42A, 42B, 42C and 42D, positioned at spaced apart locations along each arm. The temperature sensors can be of a type known in the art such as thermistors. The sensors 42A to 42D are each connected to a temperature measuring circuit, shown at 46, which generates a signal corresponding to the thermistor resistance, and thereby the temperature, of each sensor 42A to 42D.

When the arms 38 are fully retracted, the temperature sensors 42A to 42D are positioned into contact with a wall of the lower end region 36A. Because the lower end region 36A is constructed from a thermally conductive material, differences in temperature across the wellbore will be dissipated within the lower end region 36A and the temperature sensors 42A to 42D will all be at substantially the same temperature. The measurements made by the individual temperature sensors 42A to 42D can then be normalized for small variations in response, so that small differences in temperature within the fluid in the wellbore 12 can be more accurately measured.

The tool 10 includes an electronic section 48 which periodically electrically disconnects the temperature sensors 42A to 42D from the temperature measuring circuit 46 and imparts a current pulse to each sensor 42A to 42D. After the current pulse is applied to the sensors 42A to 42D, the sensors 42A to 42D are electrically reconnected to the temperature measuring circuit 46. The purpose of the current pulses will be further explained.

The angular deflection circuit 44 and the temperature measuring circuit 46 are connected to a data transceiver 50. The transceiver 50 imparts signals to the cable 26 corresponding to measurement signals conducted form the deflection circuit 44 and the temperature circuit 46. The transceiver 50 signals are conducted to the surface electronics (shown as 30 in Figure 1) where the signals can be decoded and converted into temperature measurements for each sensor and angular deflection measurements for each arm 38.

As shown in Figure 2, when the arms 38 are extended within the casing 14, each arm 38 will extend across a portion of the cross-sectional area of the space within the casing 14 located between the mandrel 36 and the part of the wall of the casing 14 contacted by that arm 38. Because the angular deflection of each arm 38 can be determined from the measurements made from the means for determining angular deflection, and the axial position of each of sensors 42A to 42D on each arm 38 is known, the position of each temperature sensor 42A to 42D with respect to the cross-section of the casing 14 can be determined.

The significance of determining the positions of the sensors 42A to 42D within the cross-sectional area of the casing 14 can be better understood by referring to Figure 3, which shows an end view of the tool 10. The mandrel 36 can be observed as positioned substantially in the center of a cross-section of the casing 14. The arms 38 are shown extending from the mandrel 36 outwardly to the wall of the casing 14. As can be observed in Figure 3, the temperature sensors 42A to 42D are positioned at a plurality of different positions within the cross-sectional area of the space within the casing 14. The different positions relative to the cross-sectional area of the casing space can be determined because the axial positions of the sensors 42A to 42D are known and the angular deflection of each arm 38 can be determined.

As previously explained, the temperature measuring circuit 46 sends signals to the surface electronics corresponding to the temperatures at each one of the temperature sensors 42A to 42D. As the tool 10 traverses the wellbore (shown as 12 in Figure 1), temperature measurements at each sensor 42A to 42D corresponding to each depth in the wellbore are recorded. Since the position of each sensor 42A to 42D within the cross-sectional area of the casing space can be determined it is possible to construct a graphic representation, or "map", of the temperature within the casing 14 at each depth in the wellbore 12. For example, Figure 4 shows a so-called "contour map" of temperature in the wellbore 12. The map in Figure 4 can include an indication of the depth 52 that the particular map represents. Isothermal contour lines t_1, t_2, t_3 and t_4 indicate positions within the casing of substantially equal temperature, and the contour lines can be generated from the temperature measurements corresponding to the sensors 42A to 42D. The contour lines t_1, t_2, t_3 and t_4 can be generated by a computer program of a type known in the art and resident in the computer in the surface electronics 30. The shape of the contours t_1, t_2, t_3 and t_4 can be indicative of the depth and type of fluid entry into the casing (indicated at 14m as a graphic representation on the contour plot of Figure 4). A plurality of maps such as that shown in Figure 4 can be generated for a plurality of different depths within the wellbore 12 in order to determine the manner in which fluid flows in the wellbore 12.

Temperature maps such as the one shown in Figure 4 can further be used to determine whether certain ones of the perforations (shown generally at 18 in Figure 1) are actively discharging fluid into the wellbore 12. For example, it is known in the art that entry of gas into the wellbore 12 is typically accompanied by a reduction in temperature due to expansion of the gas. A temperature map similar to the one shown in Figure 4 would provide indications of temperature reduction adjacent to perforations 18 through which gas is flowing, and little or no such temperature reduction adjacent to inactive perforations 18. Ambiguities on the interpretation of a particular map as to whether certain perforations are active can be resolved by repeating the process of making temperature measurements and mapping the temperature when the well is restrained from producing fluid by hydraulic closure of the flow line (shown in Figure 1 as 32), an operation known to those skilled in the art as "shutting-in" of the wellbore 2.

It is also possible, by positioning certain ones of the sensors (such as 42D in Figure 2) at the end regions 43 of the arms 38 to be in contact with the casing 14, which would enable determining whether hydraulic communication passages, called "channels", exist within the annular space between the wellbore 12 and the casing, the annular space typically being occupied by cement 16 as previously explained. Temperature differences between individual sensors 42D at the ends 43 of any of the arms 38 can be indicative of fluid movement within the annular space, thereby indicating the presence of a channel.

As previously explained, the electronic section 48 in Figure 2, called a pulsing circuit, temporarily disconnects the sensors 42A to 42D from the temperature measuring circuit 46 and apply a momentary current pulse to each sensor. The current pulse can be of variable duration, depending on, among other things, the type of sensor used. In the present embodiment, the current pulse is by way of example of one second duration. After the current pulse terminates, the pulsing circuit 48 reestablishes connection of the sensors 42A to 42D to the temperature measuring circuit 46 so that measurement of temperature of each of the sensors 42A to 42D then resumes. The current pulse, however, will have slightly elevated the temperature of each of the sensors 42A to 42D by an amount dependent on, among other things, the thermal conductivity and heat capacity of the fluid with which the sensor is in contact. The temperature of each sensor will then gradually return to the temperature of the fluid in which each sensor is in contact. The rate at which the temperature difference is reduced depends primarily on the thermal conductivity and the heat capacity of the fluid in which the individual sensor is immersed.

For example, Figure 5 shows a graphic representation of sensor temperature with respect to time for a sensor immersed in gas, as shown at 60, in oil, as shown at 62, and, in water, as shown at 64. Gas, typically having the lowest thermal conductivity and heat capacity of the three fluids, enables the greatest temperature increase in a sensor as a result of the current pulse and provides the slowest return to the fluid temperature. Oil and water, respectively, have increasing heat capacities and thermal conductivities and therefore provide successively smaller initial temperature increases and more rapid returns to the ambient fluid temperature. Each sensor can therefore provide a measurement corresponding to characteristic heat dissipation properties of the fluid in contact with that sensor.

The heat dissipation properties of the fluid in contact with the sensor can be characterized according to the increase in sensor temperature following the current pulse and according to the rate of decrease, or decay rate, in sensor temperature following the current pulse. A system operating program resident in the computer in the surface electronics (30 in Figure 1) can include a routine to measure the temperature at each sensor immediately prior to and immediately after application of the current pulse to each sensor. The program can calculate the difference in the two temperature measurements. The operating program can also scan the measurements of the sensor temperature at a plurality of spaced apart time intervals following the current pulse, these time intervals being spaced apart, for example, at about 0.05 seconds. The program then can determine a temperature decay rate based on the plurality of spaced apart temperature measurements. The decay rate and temperature increase determined for each sensor can be compared to laboratory measurements of temperature rise and decay rate made for samples of oil, gas and water. Decay rates and temperature increases determined in the wellbore can be compared by the computer to the laboratory measurements in order to determine the phase composition of the fluid in contact with each sensor.

It is possible to construct a map similar in format to the contour plot in Figure 4 which delineates positions within the casing 14 of equal heat transfer properties. Such a map of heat transfer properties can be used to determine the distribution of different fluids within the cross-section of the casing 14.

It is also to be understood that the contour plot shown in Figure 4 is only one version of "map" of the distribution of thermal properties in the wellbore 12 which can be generated using measurements from the tool 10. Many other map configurations are possible. For example, the isothermal contours t_1, t_2, t_3 and t_4 in Figure 4 could be replaced with variable colors or gray scale shading of a type known to those skilled in the art to generate a thermal "image" of the wellbore 12.

As previously stated, it is possible to determine the physical distribution of, or to "map", the heat dissipation properties of the fluids in the wellbore 12 using the tool 10. By mapping the heat dissipation properties, it is possible to determine the distribution of fluids in the wellbore. The distribution of fluids in the wellbore can be used to determine the flow regime, or manner of flow of the fluids in the wellbore, by comparing the heat dissipation maps of the wellbore to maps of the heat dissipation properties of known flow regimes. Known flow regimes can be mapped by inserting the tool 10 in a laboratory fixture known in the art as a flow-loop and mapping the heat dissipation properties of the fluids under known fluid flow conditions.

Those skilled in the art will be able to construct improvements to the present invention without departing from the spirit of the invention disclosed herein.

CLAIMS

1. An apparatus for determining distribution of thermal properties of fluids within a wellbore, the apparatus comprising:

a sonde mandrel adapted to traverse said wellbore;

radially spaced-apart arms attached to said mandrel, said arms being selectively radially extensible from said mandrel to the wall of said wellbore;

a plurality of temperature sensors disposed at spaced apart locations along said arms;

means for measuring the amount of extension of each one of said arms from said mandrel and for generating a signal corresponding to said amount of extension of each one of said arms so that the position of each of the temperature sensors within said wellbore can be determined;

a temperature sensing circuit connected to said temperature sensors for generating a signal corresponding to the temperature of each of the temperature sensors.

2. An apparatus according to claim 1 and comprising means for applying a current pulse to each of the temperature sensors momentarily to raise the temperature of said sensors, so that the thermal transient response of fluid in contact with each of the temperature sensors can be determined.

3. An apparatus according to claim 1 or 2, wherein said temperature sensors comprise thermistors.

4. An apparatus according to claim 1, 2 or 3, wherein said mandrel includes a lower end region adapted to matingly receive said arms, said lower end region comprising a material having such a high thermal conductivity that when said arms are selectively retracted said temperature sensors contact said lower end region thereby enabling normalization of response

variations of said temperature sensors.

5. An apparatus for determining distribution of thermal properties of fluids within a wellbore substantially as hereinbefore described with Figures 2 and 3 of the accompanying drawings.

6. A method of examining the fluid regime in a wellbore using the position and temperature data obtained from use of an apparatus according to any one of the preceding claims, the method comprising generating a temperature map of said conduit from said data.

7. A method of determining a fluid flow regime or fluid distribution in a conduit, the method comprising the steps of:

measuring temperature of said fluids in said conduit at known spaced apart locations within the cross-sectional area of said conduit using a tool having a plurality of temperature sensors and means for determining a position of each one of said sensors within the cross-section of said conduit; and

generating a temperature map of said conduit.

8. A method according to claim 6 or 7, wherein said step of generating a temperature map comprises generating an isothermal contour plot.

9. A method according to claim 6 or 7, wherein said step of generating a temperature map comprises generating an isothermal color plot.

10. A method according to any one of claims 6 to 9, and comprising comparing said map with maps of known flow regimes or distributions thereby to determine said flow regime.

11. A method according to claim 6 or 7, wherein said maps of known flow regimes are generated from laboratory experiments in a flow loop.

12. A method according to claim 6, when appended to

claim 2, and comprising generating a map of heat transfer properties with respect to position within the conduit.

13. A method of examining the fluid regime in a wellbore using the position and temperature data obtained from use of an apparatus according to claim 2 or 5 or to claim 3 or 4 when appended to claim 2 and comprising generating a map of heat transfer properties with respect to position within the conduit from said data.

14. A method according to claim 7 or to any one of claims 8 to 11 when appended to claim 7 and comprising the steps of:

applying current pulses to said temperature sensors momentarily to raise the temperature of said sensors;

measuring the thermal transient response at each sensor, thereby determining heat transfer properties of fluid with which each one of said temperature sensors is in contact; and

generating a map of said heat transfer properties with respect to position within the cross section of said conduit.

15. A method according to claim 12, 13 or 14 and comprising comparing the map of heat transfer properties to maps of heat transfer properties of fluid flowing in known flow regimes thereby determining said flow regime in said conduit.

16. A method of determining activity of perforations in a casing of a wellbore penetrating an earth formation comprising the steps of: measuring temperature in said wellbore at known spaced apart locations within the cross-sectional area of said wellbore using a tool having a plurality of temperature sensors and means for determining the position of each one of said sensors within the cross-section of said

wellbore, said step of measuring being performed while fluid is flowing into said wellbore from said earth formation;

generating a first map of said casing from measurements of temperature with respect to position within the cross-section of said casing made during said step of measuring;

repeating said step of measuring while said well is shut-in;

generating a second map from the measurements made while said well is shut-in; and

comparing said first map with said second map to determine active and inactive perforations.

17. A method of determining fluid conditions in a wellbore substantially as hereinbefore described with reference to the accompanying drawings.

The Patent Office

14

Application No: GB 9611264.4
Claims searched: 1-17

Examiner: M. G. Clarke
Date of search: 19 August 1996

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.O): G1N NAAJA, NAAK

Int Cl (Ed.6): E21B 47/06, 47/10

Other: Online: WPI

Documents considered to be relevant:

Category	Identity of document and relevant passage		Relevant to claims
A	US 5251479	assigned to Atlantic Richfield Co. - see especially Fig. 9 and col.5 lines 33-48	
A	US4520666	assigned to Schlumberger Technology Corpn. - whole document	

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.